ADVANCED RESOURCES INTERNATIONAL, INC.

MEMORANDUM

To: U.S. Department of Energy/Office of Fossil Energy
Date: December 7, 2004
From: Advanced Resources International, Inc.
Re: Estimated Economic Impacts of Proposed Storm Water Discharge Requirements on the Oil and Natural Gas Industry (Final)

SUMMARY

This memo summarizes the results and methodology employed to estimate the potential economic impacts of possible new storm water discharge requirements on the domestic oil and natural gas industry.

In this analysis, the economic impacts of the proposed requirements were assessed as they relate to three aspects of oil and gas operations:

- The increased costs that the industry must bear in order to comply with the proposed requirements, including consideration of the impacts on "construction" sites associated with oil and gas drilling, gas gathering, and natural gas and liquids transportation operations.
- The project delays that could result from the new requirements and the impact of these delays on the productivity of the nation's rig fleet, on the delay in revenues received from oil and gas production, and from other increased costs that could be attributable to project delays.
- The wells that would not be drilled because of permitting delays associated with the new requirements, the production lost from this foregone drilling, and the economic impacts associated with this lost production.

Critical Assumptions and Uncertainties

The economic impacts of the new storm water discharge requirements on the oil and natural gas industry will depend on a number of factors, including:

- Future levels of domestic drilling (production and injection wells), and the "construction" sites associated with these wells that are between 1 and 5 acres in size and thus could <u>potentially</u> be subject to the new requirements.
- Estimated number of "construction" projects of 1 to 5 acres in size that could fall under the proposed requirements that would be associated with natural gas gathering and gas and liquids transportation operations.
- The portion of these sites that would in fact be subject to the new requirements:

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  - In some states, existing regulations may already meet or exceed the proposed federal requirements; thus sites in these states would not incur incremental costs to comply.
  - Some sites may be eligible for waivers based on prevailing climatic and environmental conditions related to potential erosion and pollutant loading.

- The portion of sites that could be required to conduct endangered species and/or archeological or historic reviews (as required under the Endangered Species Act (ESA) and the National Historical Preservation Act (NHPA)).
- Where potential concerns are identified, the portion of sites undergoing endangered species or historic reviews that would require consultation with appropriate oversight agencies to determine how potential impacts could be mitigated.
- The costs associated with complying with these requirements, for impacted sites.
- The "unscheduled" delays that would result because of the processes imposed by complying with the new requirements, and the estimated economic implications associated with these delays.
- The portion of wells that would not be drilled because of delays and/or extra costs imposed by the new requirements that would make development unfeasible or undesirable, and the lost production and resulting economic impacts associated with wells not drilled.

Scenarios Considered

Two scenarios were defined in this analysis to represent the potential range of impacts that could result from these new requirements:

- The *Base Case* is based on citable, mostly conservative assumptions, based on published data, on estimates or assumptions derived from EPA's own economic analyses performed in 2002, and on the current requirements of the Construction General Permit (CGP) regulating storm water discharges. This scenario essentially assumes routine, systematic permitting processes, adequately staffed regulatory agencies to oversee the process, waivers and exclusions are available, and minimal use of the system to cause project delays.
- The *Higher Impact* scenario assumes that permitting processes are cumbersome and lengthy, regulatory agencies overseeing the process are inadequately staffed, some additional requirements currently under consideration get implemented in a modified CGP, waivers and exclusions are difficult to obtain, and environmental groups and discontented landowners use the permitting and project review process to delay and/or stop drilling on some leases.

Summary of Potential Impacts

Under Base Case conditions, the imposition of the proposed storm water discharge requirements could result in economic impacts to the domestic oil and gas industry amounting to the following:

- Annualized incremental costs over the 2005-2010 time period of over $380 million per year (undiscounted). Of this, over $110 million per year would be associated with increased compliance expenses, and $270 million per year would be associated with delayed production, other costs associated with project delays, and underutilized domestic drilling capacity.
- Assuming a discount rate of 5% per year, the annualized economic impacts over this same time period would amount to nearly $340 million per year, with $100 million per year associated with increased compliance expenses, and $240 million per year associated with project delays.

In addition, the proposed requirements under Base Case conditions could result in an average impact of nearly 100,000 barrels per day reduction in domestic oil production and 350 billion cubic feet (Bcf) per year loss in domestic natural gas production over the 2005 to 2010 time period. Over this time period, this could result in:

- $675 million (discounted) per year increase in the nation's expenditures for oil imports ($800 million undiscounted).
- $60 million per year less in royalties collected by the federal government ($70 million undiscounted).
- $155 million per year less paid to private landowners in oil and gas royalties ($180 million undiscounted).
- $75 million per year in lost tax revenues accruing to state government from severance taxes ($90 million undiscounted).

(*The impact due to lost sales tax and income tax revenue to federal, state, and local governments was not considered in this analysis*.)

Finally, this could result in natural gas consumers paying from $370 million to $2.3 billion more for natural gas per year due to higher natural gas prices over the 2005-2010 time period ($440 million to $2.7 billion undiscounted). The range in these estimates represents diversity of perspectives on the relative impact of decreased supplies on future natural gas prices.

These results are summarized in Table ES-1.

Cumulatively, as much as 1.3 billion barrels of oil and 15 Tcf of natural gas supplies would not be produced by 2025 under Base Case conditions.

In contrast, under the Higher Impact scenario, the imposition of the proposed storm water discharge requirements could result in the following annualized incremental costs over the 2005-2010 time period:

- On an undiscounted basis, over $2.9 billion per year. Of this, over $0.3 billion per year would be associated with increased compliance expenses, with nearly $2.6 billion per year associated with project delays.
- On a discounted basis, the economic impacts over this same time period would average $2.4 billion per year, with $270 million per year associated with increased compliance expenses, and nearly $2.2 billion per year associated with delays.

In addition, the proposed requirements under the Higher Impact scenario could result in an average impact of 280,000 barrels per day reduction in domestic oil production and over one trillion cubic feet (Tcf) per year loss in domestic natural gas production over the 2005 to 2010 time period, resulting in the following:

- $2.0 billion (discounted) per year increase in the nation's expenditures for oil imports ($2.4 billion undiscounted).
- $180 million per year less in royalties collected by the federal government ($210 million undiscounted).
- $465 million per year less paid to private landowners in oil and gas royalties ($545 million undiscounted).
- $225 million per year in lost tax revenues accruing to state government from severance taxes alone ($265 million undiscounted).

This could result in natural gas consumers paying from $1.1 to $6.5 billion more for natural gas per year due to higher natural gas prices ($1.3 to $7.9 billion undiscounted).

Cumulatively, as much as 3.9 billion barrels of oil and 45 Tcf of natural gas supplies could be lost by 2025 under the Higher Impact scenario.

Substantial uncertainty is associated with many of the assumptions used in this analysis. Moreover, since EPA has yet to publish its proposed requirements for Phase II as applied the oil and gas sector (if it is determined that this sector is not exempt), certain assumptions about compliance requirements may turn out to be different than what EPA currently requires under the CGP. For the most part, the characterization of new compliance requirements in this analysis is based on requirements for sites that are currently subject to storm water discharge requirements under the CGP.

The uncertainties characterizing the range of potential economic impacts presented in this assessment primarily relate to the permitting delays that would result under the new requirements. These pertain to the anticipated processes required for endangered species and historic reviews, and the time it might take to process permit applications, make determinations, and grant approvals. If these processes proceed efficiently and according to schedule, anticipated economic impacts (although still considerable) can be minimized. On the other hand, if these processes are cumbersome, contentious, and prone to delays, the economic impacts can be quite large, with substantial impacts on domestic energy supplies, our nation's balance of trade and dependence on foreign energy supplies, and the price Americans pay for the energy they consume.

Table ES-1

Estimated Economic Impacts of Phase II Stormwater Discharge Requirements on the Domestic Oil and Natural Gas Industry

	Estimated Annualized Impacts (2005 - 2010)			
	Base Case		Higher Impact Scenario	
	Discounted	Undiscounted	Discounted	Undiscounted
Costs of Compliance (MM $/yr)	$99	$112	$268	$319
Costs of Delays (MM$/yr)	$239	$270	$2,157	$2,564
Total	**$338**	**$382**	**$2,425**	**$2,883**
Crude Oil Prod. (MMB/day)	0.094		0.282	
Natural Gas Prod. (Bcf/year)	349		1,048	
Increased Imports Exp. (MM $/yr)	$676	$799	$2,029	$2,398
Lost Federal Royalties (MM $/yr)	$60	$71	$181	$212
Lost Private Royalties (MM $/yr)	$155	$182	$464	$545
Lost State Sev. Taxes (MM $/yr)	$75	$88	$226	$265
Inc. Exp. for Natural Gas (MM $/yr)				
EIA Basis	$367	$443	$1,063	$1,281
NPC Basis	$2,259	$2,725	$6,538	$7,883

BACKGROUND

Amendments to the Clean Water Act (CWA) require that the Environmental Protection Agency (EPA) establish tiered regulations for storm water discharges under its National Pollutant Discharge Elimination System (NPDES). In the early 1990s, EPA adopted regulations for Phase I, to include industrial runoff, runoff from municipal storm sewers serving 100,000 or more, and construction activities greater than 5 acres. EPA developed several model general permits to cover these categories. Because most oil and gas sites do not disturb more than 5 acres, few oil and gas sites were covered under these permits.

In 1999, EPA published proposed regulations for Phase II, as stipulated in the CWA, to cover smaller separate municipal storm sewers and construction sites that disturb from 1 to 5 acres. Most onshore oil and gas well sites disturb from 1-5 acres (including lease road and well pad) and therefore, based on EPA's determination, should be subject to the Phase II requirements.

On March 10, 2003, EPA issued a decision (Federal Register, Vol. 68, No. 46, pp. 11325-11330) where the determination of the applicability of the storm water discharge permit requirements on oil and gas operations was deferred to March 10, 2005, because EPA concluded that it had not adequately performed economic impact analyses related to this industry sector.

The objective of this effort is to build upon the earlier assessment and develop a more accurate, up-to-date, citable and industry-reviewed quantitative assessment of the potential economic impacts of the Phase II storm water discharge requirements, if implemented, on the domestic oil and gas industry.

OVERVIEW OF APPROACH

Thousands of onshore oil and gas wells may be required to comply with the requirements of the Construction General Permit (GCP) for storm water discharges if EPA determines that the construction activities at oil and gas drilling sites are subject to Phase II requirements. In addition, activities associated with gas gathering, processing, and liquids and gas transportation operations that impact between 1 and 5 acres could also be subject to the proposed Phase II requirements. Complying with the CGP could delay the process of preparing sites by one to several months, could cause operators additional compliance expenses, and could result in some operators deciding to forego some drilling because of the constraints imposed by the permitting process.

Industry maintains that the environmental impact from isolated small oil and gas sites in mostly rural areas is likely to be minimal, and that incremental compliance requirements are not justified based on these impacts. They claim that this is especially true given the fact that the "construction" prior to drilling operations (since drilling operations themselves are exempt under Section 403(1)(2) of the CWA) generally only lasts from 3 to 7 days at most locations. However, EPA's current position is that the exemption does not apply to clearing, grading, and excavating activities, primarily related to site clearing and road building, prior to the drilling rig arriving on site.

Two scenarios were defined in this analysis to represent the potential range of impacts that could result from these new requirements on oil and gas operations:

- The *Base Case* is based on citable, mostly conservative, assumptions, based on published data, on estimates or assumptions derived from EPA's own economic analyses performed in 2002, and on the current requirements of the CGP. This scenario essentially assumes routine, systematic permitting processes, adequately staffed regulatory agencies to oversee the process, waivers and exclusions are available, and minimal use of the system to cause project delays.
- The *Higher Impact* scenario assumes that permitting processes are cumbersome and lengthy, regulatory agencies overseeing the process are inadequately staffed, some additional requirements currently under consideration get implemented in a modified CGP, waivers and exclusions are difficult to obtain, and environmental groups and discontented landowners use the permitting and project review process to delay and/or stop drilling on some leases. *It is important to note, however, that the impacts estimated for this scenario should not necessarily be considered to be those associated with a "worst case" scenario*. As illustrated in this memo and in Appendix A, in many cases, assumptions that could lead to even greater assessed impacts could have been used.

The approach used for developing the estimated economic impacts on the oil and gas industry resulting from the Phase II requirements is described in the following paragraphs. Some of the justification for this approach and the assumptions underlying it, along with other potential assumptions considered, is provided in Appendix A.

Estimate of the number of production well drilling sites between 1 and 5 acres

The estimated number of oil and gas well sites potentially subject to the Phase II requirements corresponds to forecasts of domestic oil and gas drilling. In this analysis, future well drilling levels are assumed to be consistent to drilling forecasts of the Energy Information Administration (EIA) in its Reference Case of the 2004 Annual Energy Outlook (AEO) (Reference 9). For gas well drilling, AEO 2004 forecasts are comparable to those assumed by the National Petroleum Council (NPC) in their most recent natural gas study (Reference 14). The NPC did not report their forecasts for oil wells.

All sites associated with these forecast wells drilled were assumed to fall within the 1-to-5-acre size category.

Estimate of the number of injection well drilling sites between 1 and 5 acres

Estimates of the number of injection wells sites in the U.S. are based on current ratios of operating injection wells to oil production wells in Texas and California. This results in approximately 1 injection well for every 4 oil production wells. This includes all enhanced recovery (both water and gas injection) and brine disposal wells, but not injection wells used for gas or hydrocarbon storage. Rough estimates nationally, using EPA data for all Class II injection wells (http://www.epa.gov/safewater/uic/classii.html), which includes storage wells, and *World Oil* magazine estimates (Reference 15) of producing oil wells in the U.S., would make this number more like 1 injector for every 3 oil production wells, implying the 1 in 4 estimate may be somewhat conservative..

All injection well sites were assumed to fall within the 1-to-5-acre size category.

Estimate of the number of gas gathering/processing sites between 1 and 5 acres

For this project, the Gas Processors Association (GPA) submitted an estimate of the number of sites associated with gas gathering and/or processing operations that are between 1 and 5 acres in size and thus could fall within the purview of the Phase II requirements. GPA is the trade organization (with approximately 100 members) of companies engaged in the processing of natural gas, or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA's membership accounts for approximately 92% of all natural gas liquids produced by the midstream energy sector in the United States.

GPA estimated that there are currently 2,370 construction projects in the natural gas midstream sector that are between 1 and 5 acres in area. These projects primarily pertain to sties associated with the gathering and transportation of natural gas and natural gas liquids from the wellhead to the initial processing facility. A 50-foot right-of-way width was assumed for determining the total footprint area of an average or representative project (Reference 13)

For purposes of this analysis, this number of projects is assumed to be applicable annually.

Estimate of the number of gas and liquids transportation sites between 1 and 5 acres

The number of current projects associated with gas and liquid transportation operations that would fall under the Phase II requirements in the 1-5 acre size range was estimated based on estimates made by a major U.S. gas transportation company for its own operations. They developed their estimate based on the number of currently permitted company projects (under Phase I requirements), compared to the estimated number of projects they have in the 1 to 5 acre size range. This included both identified projects and an estimate of the number of projects that are currently "unidentified," but that were determined to be likely based on the number of identified projects. This estimate of sites associated with natural gas pipeline activities included the installation of small segments of new pipelines, surface facility additions or expansions, and repair/replacement activities in which the original intent was to repair or replace a segment of pipeline. The estimate does not include situations where the original intent complied with EPA's definition of maintenance, but at some point in the work it is determined that it is necessary to repair or replace a segment of pipeline.

Based on this company's estimate, and the miles of gas pipeline within this company to which their estimate applies, it was determined that, nation-wide, there would be approximately one project falling under the Phase II requirements per 278 miles of pipeline. Based on the number of miles of natural gas and liquid pipelines in the U.S., this would amount to about 1,500 sites, assumed to be applied annually.

Portion of these 1-5-acre sites subject to new requirements

Taking into consideration all of the potential sites described above results in an average of 29,600 sites annually. However, only a portion of these sites will be in states with requirements currently less stringent than the proposed Phase II requirements. In the Development Document for the Phase II rulemaking, EPA estimated that 41% of developed acreage is in states with existing state programs, and would not have to modify their permits to meet the new requirements (Reference 2). Based on this, under Base Case conditions, this analysis assumed that 60% of the sites would be subject to the proposed requirements.

Industry is concerned that a large portion of oil and gas well sites would be subject to the new requirements. For example, EPA is the jurisdictional agency for gas pipeline construction activities in three of the major oil and gas producing states -- New Mexico, Oklahoma, and Texas. Of the nine states which manage the storm water permit program, eight have adopted EPA's two-year postponement: Arkansas, Colorado, Illinois, Iowa, Kansas, Louisiana, Nebraska, and Wyoming. Most of these are major oil and gas producing states. The one remaining state, Missouri, has developed a state program. Since all of these states have followed EPA's lead on the postponement for the oil and gas industry, it is reasonable to assume that they will follow EPA's lead on implementation of the Phase II permit requirements to the oil and gas industry. Given this scenario, the Higher Impact scenario assumes that 90% of the sites would be subject to the new requirements.

<u>Portion of these 1-5-acre sites potentially subject to waivers</u>

A portion of sites could be subject to one of several waivers that may be obtainable based on certain criteria. One pertains to a Rainfall Erosivity Factor (REF), which is used to predict soil loss from construction sites. Another is based on a Total Maximum Daily Load (TMDL) calculation, which pertains to the maximum amount of pollutant that a water body can receive and still meet water quality standards. In this analysis, based on estimates developed by EPA (Reference 5), it was assumed in the Base Case that 15% of sites will receive either an REF or TMDL waiver (Reference 5), beginning in 2005.

In contrast, some claim that few, if any, sites would likely be subject to such waivers. Permitting authorities have the option to not allow waivers. In many cases, the times of year during which the waivers could be obtained are minimal and sporadic. Moreover, a waiver may not necessarily waive <u>all</u> permit requirements, but only allows EPA to waive "otherwise applicable requirements in a general permit." Finally, should operators try to schedule drilling to coincide with time windows during the year when waivers could be obtainable, it could further complicate the logistics of leasing, permitting, and scheduling drilling rigs (see discussion below).

Therefore, under the Higher Impact scenario, it is assumed that no such waivers could be obtainable.

<u>Estimate of costs to be incurred by wells subject to the new requirements</u>

Taking into consideration those in states where oil and gas sites would be subject to the new requirements, and those sites potentially subject to the TMDL or the REF waivers, an estimated 15,100 sites per year, on average, could be impacted under the Base Case. Under the Higher Impact scenario, 24,700 sites would be subject to the new requirements per year, on average. Of these, 83% correspond to well drilling sites.

In this analysis, the costs assumed to be associated with compliance requirements for these sites are consistent with estimates by industry and/or EPA (in the case of EPA, they are generally associated with small construction sites; EPA did not originally look at oil and gas drilling sites specifically). *The compliance costs considered are only those associated with filing the necessary documents under the CGP*. They do not include any incremental operational costs that may be required to ensure compliance (such as implementing Best Management Practices (BMPs)) or to mitigate any possible impacts to endangered species or historic sites.

EPA believes that only a portion of the sites falling under the Phase II requirements would need to conduct endangered species reviews, and an even smaller portion would require consultation with appropriate regulatory or oversight agencies to determine how potential impacts could be mitigated.

In contrast, industry believes that most (if not all) sites could be subject to an ESA review. Moreover, they believe that the costs and efforts associated with conducting these reviews are likely to be more complicated and lengthy than EPA assumed, especially given industry's concern that current personnel levels in responsible agencies are not sufficient to handle the major increase in the number of reviews that these new requirements would impose on them. Finally, some in industry feel that these requirements will be used by environmental groups and a few landowners to indefinitely stall and/or stop drilling operations at certain locations.

In the draft Phase II requirements, provisions were proposed to require storm water discharge permit applicants to conduct reviews to ensure the protection of historic places under the National Historical Preservation Act (NHPA). However, the final CGP does not include these requirements. However, EPA is continuing discussions with the Advisory Council on Historic Preservation on potential future requirements, and the current CGP contains a "re-opener clause" which can allow EPA, at a later date, to modify the GCP based on the results of those discussions.

Given these two possibilities, the estimated proportion of sites subject to the new requirements, for the two scenarios considered in this assessment, were estimated based on the following:

- Based on EPA's economic impact assessment (Reference 1), both the Base Case and Higher Impact Scenario assume 40% of sites would have endangered species in proximity and would require a review. Of these, 3% of sites would require a consultation in the Base Case, and, in the Higher Impact scenario, 20% of sites would either require consultation or landowners and/or parties opposing drilling would initiate a consultation.
- A lower proportion of sites are likely to be subjected to a historic review, compared to the endangered species review. For this analysis, no sites are assumed to be subject to a historic review in the Base Case, while, in the Higher Impact scenario, 20% of the sites are assumed to require a historic review, and of these, 10% are assumed to require consultation.

A significant and growing proportion of the onshore oil and gas wells drilled in the U.S. are on lands managed by the federal government. As part of the process of issuing leases on these lands, an Environmental Impact Statement (EIS) must be developed, which would include an assessment of the impact of oil and gas leasing and development on endangered species and historical places. In general, this is conducted for the entire area subject to leasing, and not at the level of individual leases or wells. Moreover, public participation is a critical aspect of the process for issuing permits on federal leases. In this regard, there may be some overlap between the assumptions developed by EPA on the portion of sites requiring endangered species reviews and those sites corresponding to activities on federal lands. Unfortunately, sorting out this overlap, if it exists, would be difficult. Consequently, for purposes of this economic impact assessment, EPA's assumptions are used.

The estimated costs associated with compliance, for the two scenarios considered in this assessment, were assumed as follows:

- Incremental compliance costs would be incurred by activities associated with developing the information and meeting the requirements for filing a Notice of Intent (NOI), which would be required for each site subject to the new requirements. This would include activities to ensure that a Storm Water Pollution Prevention Plan (SWPPP) is completed, BMPs are installed according to SWPPP, periodic inspections are conducted, and the site is stabilized prior to filing a Notice of Termination (NOT). This analysis assumes that this will require approximately 72 person-hours, amounting to $6,000 per well. This applies to both the Base Case and the Higher Impact scenario.
- In the Base Case, 36 person-hours are assumed to be required for the endangered species review, amounting to $3,000 per site. For the consultation, 160 person-hours, amounting to $13,333 per site, are assumed to be required under Base Case conditions. Under the Higher Impact scenario, it is assumed that the consultation process takes twice as long, amounting to 320 person-hours and $26,667.
- 48 person-hours are assumed to be required to conduct the historic review, amounting to $4,000 per site. For consultation, 320 hours, amounting to $26,667 per site, are assumed. These are assumed to be applicable in the Higher Impact scenario only.

<u>Estimate of economic impacts associated with delayed production</u>

The new proposed requirements are likely to impose additional delays for drilling projects, because of the burdens potentially posed by new endangered species and historic reviews and/or consultations. A routine, informal endangered species consultation may take several months or more, assuming that approval is forthcoming. A surface owner or environmental group that opposes drilling can use this process to impose unending delays, even if the endangered species allegations are unsubstantiated.

This analysis assumes some "unscheduled" delays are likely to result from this process. The nature and extent of these delays are hard to predict, and may decrease with time as experience is gained and/or staffing levels are adjusted in the appropriate oversight agencies. For this analysis, the characterization of these effects is based on industry and EPA characterization of the activities involved, current review and consultation processes for larger sites in representative states, and the assumption that delays would be inevitable given the substantially increased review burden imposed on regulatory agencies once the Phase II requirements are in place.

Estimated length of time associated with project delays. The following delays associated with the endangered species and archeological review and consultation process were assumed in this analysis:

- An "unscheduled" delay of one week for the endangered species review, and 3 weeks for the consultation, was assumed for the Base Case.
- Under the Higher Impact scenario, delays of 3 weeks for the endangered species review and one month for the historic review, and 9 weeks for the endangered species consultation and 3 months for the historic consultation, were assumed.

It is important to note that these estimated delays could be considerably greater than assumed here. In a brief filed by the National Resources Defense Council (NRDC) with the 7th Circuit Court on July 28, 2004, they argue, among other things, that the self-implementing ESA provisions of the CGP should not be allowed under the ESA, and that EPA should be required to review each operator's ESA and, in consultation with the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), determine that no adverse effects are likely to any endangered species in each project area. In this assessment, the delays assumed only apply to those traditionally experienced for projects currently seeking storm water discharge permits, which do not traditionally involve EPA review. The implications associated with the NRDC recommendations that EPA review each permit were not considered, but if NRDC were to prevail, the likely delays in the endangered species reviews would be longer that assumed in this assessment, increasing the potential for lease forfeiture and lost reserves.

The NRDC also argues in their brief that the general permit does not comply with the CWA because EPA does not individually review the NOIs and SWPPPs prepared under the general permit process and the permit process does not provide for public notice, comment, and opportunity for public hearing on NOI's and SWPPPs. NRDC successfully made the public participation argument to the 9th Circuit with respect to NOIs submitted for storm water discharges from Municipal Separate Storm Sewer Systems. However, in this assessment, no delays associated with the process of submitting NOIs and SWPPPs are assumed.

Impact of project delays on drilling fleet efficiency and/or drilling costs. The delays imposed by the new endangered species and historic reviews and/or consultations would likely result in an increase in the time rigs will be idle waiting for permit approval. In some cases, operators would lose access to the scheduled rig, because of other scheduled obligations for the rig, and the well would not be drilled. For purposes of this analysis, one impact is represented by an increase in drilling expenses (rig operators would still need to recover their costs even if the rigs are idle), associated with the time rigs would be idle waiting for approvals. This was based on an average well cost of $711,000 per well (average for 2002, according to Reference 11), and an average rig utilization rate of 70% (average for the 1988 to 2001 time period, according to Reference 12). *It is important to note that the impact associated with these increased rig costs on the economic viability of drilling prospects was not explicitly considered, except to the extent that it's included in the assessment of energy supply and economic impacts due to lost production discussed below.*

Lost value associated with project delays. Because of delays associated with the review and consultation process, income from production from wells subject to these delays will come later than would otherwise be the case. Consequently, the ultimate value of this production, on the basis of discounted cash flow, will be less. The impact on the value of production was estimated by the following approach:

- The amount of production associated with each well impacted was estimated by using EIA forecasts of reserve additions, production, and well drilling (Reference 9) to estimate average production per well drilled.
- The value associated with the delayed production for the impacted wells was estimated by multiplying the estimated production per well, times the number of days associated with the "unscheduled" delays, times the price of that production, times the daily discount rate applied to the delayed production.
- The average daily discount rate assumed was based on the average annual return on investment for the domestic exploration and production (E&P) industry for 2001 and 2002, which was 9.7% (Reference 10).

Increased operator royalty payments due to project delays. Many mineral lease agreements have development commitments that require that drilling occur within a specified period of performance, with financial penalties (often in the form of increased royalty payments) for failure to perform. This analysis estimates the impacts of project delays on operator royalty obligations, assuming that 5% of the impacted wells would incur higher royalty obligations under Base Case conditions, and that a 2.5% increase in royalty rate would have to be paid because of the delay for the affected wells (Reference 3). The Higher Impact scenario assumes twice as many wells would incur the higher royalty obligations.

Estimate of energy supply and economic impacts associated with lost production

Ownership of mineral interests has become increasingly fractured, with numerous undivided owners. Thus, the acquisition of drilling rights can become very expensive, time consuming, and a major risk concerning the development of a prospect. The process for obtaining drilling rights can take several years. Moreover, the primary terms of these leases vary; while most terms are around three years, many are one year or less. By the time an operator obtains the right to drill; only a few weeks or days may remain within many of the leases in which to drill. Many prospects can be dropped, and reserves and potential production associated with them lost, due to problems and difficulties associated with fulfilling all of these multiple lease obligations.

Wells not drilled due to proposed Phase II requirements. One independent operator reported that his last 14 oil and gas exploration and development prospects averaged over 100 negotiated leases from separate mineral interest owners for each prospect. Several of his larger prospects required over 300 separately negotiated leases. Of these 14 prospects, this operator believes that from four to six (28% - 42%) would most likely not have been pursued had the new storm water discharge requirements been in place, due to the difficulties the process would cause in the logistics associated with acquiring leases, obtaining permit approvals, scheduling rigs, and meeting lease commitments.

In addition, because of title, surface issues, and ongoing geology, engineering and environmental studies, the initial drill site location is often not established until the majority of the leases have been negotiated. A permit application would not be submitted until the drill site has been established. Moreover, often the location of subsequent wells to be drilled is dependent on the reservoir geology that is determined from prior drilling efforts. When more than one well is drilled, time is of the essence to keep drilling wells. If there is any delay, the operator may lose access to his rig.

In this analysis, under the Base Case, 5% of the wells otherwise forecast in the 2004 EIA AEO Reference Case are assumed not to be drilled, and the leases forfeited, with the resulting production and economic impacts. Under the Higher Impact scenario, 15% of the wells otherwise forecast in the 2004 EIA AEO Reference Case are assumed not to be drilled.

Lost production from wells not drilled. The estimated production associated with these wells not drilled was based on the AEO 2004 Reference Case results for well drilling, average reserve additions associated with these wells, and the average ratio of production-to-reserves over the 2005 to 2025 forecast time period.

Forfeited bonus and lease rental payments due to project delays. Similarly, many lease agreements have performance specifications that require lease development and drilling occur within a certain period of time or the lease is forfeited. In these cases, lease bonus payments and rentals costs incurred would be wasted. For this, impacts are estimated assuming that the wells affected would lose their leases and not be drilled, having paid bonus and rental payments associated with the forfeited leases of $125/acre, with an average lease size of 320 acres/well (Reference 3).

Lost transfer payments from wells not drilled. Estimates of the lost federal royalties, private royalties, and severance taxes associated with the oil and gas not produced were based on the forecast lost production; EIA forecast oil and gas prices, an average 12.5% royalty rate, and an average 5% severance tax rate, and an estimate, based on previous analyses, of the amount of forecast production coming from federal lands. In this assessment, 28% of total oil and gas production was assumed to come from federal leases, based on previous DOE analyses (Reference 22).

The impact due to lost sales tax and income tax revenue to federal, state, and local government was not considered in this analysis.

Higher import payments due to lost domestic production. In the case of crude oil, it was assumed that every barrel of domestic production lost would need to be replaced by a barrel of imported oil. Estimates were made of the amount spent on purchasing imported oil to replace the domestic production foregone by multiplying the estimated increase in imports by the forecast world oil prices.

Higher consumer expenditures for natural gas. In addition, based on a number of previous runs performed by EIA's National Energy Modeling System (NEMS), a rule of thumb was developed to establish the impact of lost natural gas production on future natural gas prices. Based on a review of these previous runs (References 9 and 16), it was determined that natural gas prices increase by $0.13 for every Tcf loss in natural gas production. A similar analysis was conducted of various supply-related sensitivity cases in a recent NPC natural gas study (Reference 14). This analysis showed the impact to be over six times as large, with natural gas prices increasing by $0.82, on average, for every Tcf loss in natural gas production.

In this assessment, results were developed using both the EIA and NPC characterizations. In each case, the assumed change was applied to the decrease in production in 2025, and the increase in price due to lost production was assumed to accumulate linearly over the 2005 to 2025 time period.

The estimated increase in expenditures associated with these increased gas prices were estimated by this change in price multiplied by EIA forecasts of future natural gas consumption at the higher prices.

Estimate of benefits in present value (discounted) dollars

In this analysis, economic impacts were estimated year-by-year through 2025. This timeframe is consistent with the forecast horizon of the AEO 2004, which presently extends to 2025. Because these impacts were calculated in the form of an annual time series, the time series of impacts are estimated in two ways:

- In terms of average annualized and cumulative impacts in present day dollars (2002 dollars).

- In terms of average annualized and cumulative impacts in present value terms, or discounted dollars, using an assumed discount rate of 5 percent.

The choice of the discount rate is one of the most controversial and important topics within cost-benefit analysis. The Office of Management and Budget (OMB) recommends a 7 percent discount rate for social benefit-cost analysis (References 17 and 18). In an EPA report of guidelines for its economic analyses (Reference 19), a 3 percent discount rate is recommended. However, EPA's recent financial impact analysis of the Clear Skies Act used a 5.3 percent discount rate (Reference 20) and their benefit analysis of the Clear Skies Act forecasts benefits using both a 3 percent and 7 percent rate (Reference 21).

Therefore, for this study, a discount rate of 5 percent was selected as a reasonable "mid-point" rate.

This report provides the benefits both discounted and non-discounted, leaving the reader to decide which values are most appropriate.

In addition, average annual and cumulative benefits were estimated over two different time series:

- For the time period from 2005 to 2025, to represent the full time frame for which the AEO 2004 forecasts future oil and gas industry activity.
- For the time period from 2005 to 2010, to represent the impact over the first five years after which the proposed requirements are assumed to be in place.

SUMMARY OF RESULTS

Given the assumptions used in this analysis, under Base Case conditions, as shown in Table 1, the imposition of the proposed storm water discharge requirements could result in increased compliance and delay costs to the domestic oil and gas industry of $370 to $380 million per year (the range represents the difference in impacts annualized (and undiscounted) over a five-year (2005-2010) time horizon or a 20-year (2005 to 2025) time period). Of this, $110 to $115 million per year would be associated with increased compliance expenses, with the majority of the costs associated with filing of the NOI. From $255 to $270 million per year would be associated with the impacts associated with delayed production, forfeited leases and increased royalty obligations by operators; and the costs associated with underutilized domestic drilling capacity (which represents the largest portion of these costs). By 2025, these requirements would result in cumulative cost impacts on the order of $7.8 billion.

Under the Higher Impact scenario, the imposition of the proposed storm water discharge requirements could result in cost impacts to domestic oil and gas industry of on the order of $2.8 to $2.9 billion annually. Of this, from $320 to $330 million per year would be associated with increased compliance expenses, and $2.5 to $2.6 billion per year would be associated with project delays and delayed production. By 2025, these requirements would result in cumulative cost impacts on the order of over $66 billion.

Table 1
Estimated Impacts of Potential New Stormwater Discharge Requirements on Domestic Oil and Gas Drilling Operations (Undiscounted 2002 Dollars)

	Base Case			Higher Impact Scenario		
	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)
	2005-2025	2005-2010		2005-2025	2005-2010	
Costs of Compliance						
NOI Permit Costs	$91	$89	$1,901	$149	$143	$2,963
ESA Review & Consultation	$24	$24	$507	$128	$124	$2,568
NHPA Review & Consultation	$0	$0	$0	$53	$51	$1,054
	$115	**$112**	**$2,408**	**$330**	**$319**	**$6,585**
Costs of Delays						
Increased Royalties	$36	$33	$759	$117	$106	$2,337
Forfeited Lease Bonuses	$25	$24	$523	$120	$116	$2,408
Increased Expenses for Idle Rigs	$119	$116	$2,504	$1,587	$1,526	$31,736
Lost Value of Delayed Production	$75	$96	$1,578	$649	$816	$22,962
	$255	**$270**	**$5,363**	**$2,473**	**$2,564**	**$59,442**
Grand Total	**$371**	**$382**	**$7,771**	**$2,802**	**$2,883**	**$66,027**

As illustrated in Table 2 for one set of cost impacts, showing only the compliance cost impacts over the 2005 to 2025 time period (undiscounted) associated with the different types of oil and gas industry sites considered in this assessment, the vast majority of impacts are associated with oil and gas well drilling.

Discounted economic impacts, assuming a 5% per year discount rate, are summarized in Table 3. As shown, the imposition of the proposed storm water discharge requirements could result in cost impacts to domestic oil and gas industry of nearly $340 million per year annualized over a five-year (2005-2010) time horizon, or nearly $240 million over a 20-year (2005 to 2025) time period. By 2025, these requirements would result in cumulative economic impacts on the order of $4.9 billion discounted.

Under the Higher Impact scenario, the imposition of the proposed storm water discharge requirements could result in discounted cost impacts to domestic oil and gas industry of on the order of $2.4 billion annually for the first five years, and $1.8 billion per year over the next 20 years, on average. By 2025, these requirements would result in cumulative discounted cost impacts on the order of nearly $36 billion.

Table 2

Estimated Impacts of New Stormwater Discharge Requirements Cost Impacts by Site Type, 2005 to 2025 Time Period (Undiscounted Dollars)

	Base Case		Higher Impact Scenario	
	Est. Impacts Annualized (MM$/year)	Cum. Impacts to 2025 (MM $)	Est. Impacts Annualized (MM$/year)	Cum. Impacts to 2025 (MM $)
Compliance Costs by Site Type				
Production Wells	$95	$1,989	$268	$5,351
Injection Wells	$5	$104	$15	$305
Gas Gathering/Processing	$9	$193	$28	$569
Gas and Liquids Transporatation	$6	$122	$18	$360
Total	**$115**	**$2,408**	**$330**	**$6,585**

Table 3

Estimated Impacts of Potential New Stormwater Discharge Requirements on Domestic Oil and Gas Drilling Operations (Discounted Dollars)

	Base Case			Higher Impact Scenario		
	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)	Est. Impacts Annualized (MM$/year)		Cum. Impacts to 2025 (MM $)
	2005-2025	2005-2010		2005-2025	2005-2010	
Costs of Compliance						
NOI Permit Costs	$61	$78	$1,189	$101	$120	$1,899
ESA Review & Consultation	$15	$21	$317	$82	$104	$1,646
NHPA Review & Consultation	$0	$0	$0	$34	$43	$675
	$76	**$99**	**$1,506**	**$217**	**$268**	**$4,220**
Costs of Delays						
Increased Royalties	$22	$29	$467	$67	$89	$1,343
Forfeited Lease Bonuses	$16	$21	$327	$77	$97	$1,543
Increased Expenses for Idle Rigs	$74	$103	$1,564	$1,017	$1,282	$20,336
Lost Value of Delayed Production	$50	$85	$1,055	$412	$689	$8,233
	$163	**$239**	**$3,413**	**$1,573**	**$2,157**	**$31,454**
Grand Total	**$238**	**$338**	**$4,918**	**$1,789**	**$2,425**	**$35,674**

As described above, the new Phase II storm water discharge requirements, if imposed on the oil and gas industry, could also lead to oil and gas wells not being drilled, resulting in lost domestic oil and natural gas production, and significant economic impacts associated with this foregone production. For example, as shown in Table 4, under Base Case conditions, the proposed requirements could result in nearly 100,000 barrels per day reduction in domestic oil production over the first five years, and a 170,000 barrel per day loss in production, on average, over the 2005 to 2025 time period. Similarly, nearly 350 Bcf per year of natural gas would not be produced on average, in the first 5 years, and an average of over 710 Bcf per year would be lost over the 2005 to 2025 time horizon. Cumulatively, as much as 1.3 billion barrels of oil and 15 Tcf of natural gas supplies could be lost over the 2005 to 2025 time period under the Base Case.

Table 4

Estimated Impacts of Potential New Stormwater Discharge Resulting from Reduced Drilling

	ANNUALIZED IMPACTS (DISCOUNTED AND UNDISCOUNTED)							
	Base Case				Higher Impact Scenario			
	2005-2025		2005-2010		2005-2025		2005-2010	
	Disc	Undisc	Disc	Undisc	Disc	Undisc	Disc	Undisc
Crude Oil Production Lost								
Annual (MMB/day)	0.171		0.094		0.513		0.282	
Cumulative (Billion Barrels)	1,310		206		3,930		617	
Natural Gas Production Lost								
Annual (Bcf per year)	714		349		2,143		1,048	
Cumulative (Bcf)	15,002		2,096		45,005		6,288	
Increased Crude Oil Imports								
Annual (MMB per day)	0.171		0.094		0.513		0.282	
Increased Exp. For Imports								
Annual ($ Million)	$879	$1,562	$676	$799	$2,636	$4,686	$2,029	$2,398
Increased Federal Royalties								
Annual ($ Million)	$87	$158	$60	$71	$260	$473	$181	$212
Increased Private Royalties								
Annual ($ Million)	$223	$405	$155	$182	$668	$1,215	$464	$545
Increased State Severence Taxes								
Annual ($ Million)	$108	$197	$75	$88	$325	$591	$226	$265
Increase in WH Gas Prices ($/Mcf)								
EIA Basis	$0.04	$0.07	$0.01	$0.02	$0.11	$0.21	$0.04	$0.05
NPC Basis	$0.22	$0.44	$0.09	$0.11	$0.67	$1.31	$0.27	$0.33
Increased Expenditures for Natural Gas								
Annual ($ Million)								
EIA Basis	$1,024	$2,030	$367	$443	$2,892	$5,716	$1,063	$1,281
NPC Basis	$6,302	$12,487	$2,259	$2,725	$17,795	$35,169	$6,538	$7,883

Over the 2005 to 2010 time period this could result in:

- $675 million (discounted) per year increase in the nation's expenditures for oil imports ($800 million undiscounted).
- $60 million per year less in royalties collected by the federal government ($70 million undiscounted).
- $155 million per year less paid to private landowners in oil and gas royalties ($180 million undiscounted).
- $75 million per year in lost tax revenues accruing to state government from severance taxes alone ($90 million undiscounted).

Significantly larger impacts could result if averaged over the entire 2005 to 2025 time period for which the analysis was performed. Over this time period, the following impacts would result:

- $880 million (discounted) per year increase in the nation's expenditures for oil imports ($1.6 billion undiscounted).
- $90 million per year less in royalties collected by the federal government ($160 million undiscounted).
- $220 million per year less paid to private landowners in oil and gas royalties ($400 million undiscounted).
- $110 million per year in lost tax revenues accruing to state government from severance taxes alone. ($200 million undiscounted).

This does not include consideration of the impact due to lost sales tax and income tax revenue to federal, state, and local governments.

Finally, this could result in natural gas consumers paying from $1.0 to $6.3 billion more (discounted) for natural gas per year, on average, over the 2005 to 2025 time horizon due to higher natural gas prices ($2.0 to $12.5 billion undiscounted). Over the 2005 to 2010 time period, from $370 million to $2.3 billion more (discounted) more will be paid for natural gas per year, on average, ($440 million to $2.7 billion undiscounted)

In contrast, under the Higher Impact scenario, the proposed requirements could result in 280,000 barrels per day reduction in domestic oil production over the first five years, and over 500,000 barrel per day loss in production, on average, over the 2005 to 2025 time period. Similarly, over one Tcf per year of natural gas would not be produced on average, in the first 5 years, and an average of over 2.1 Tcf per year would be lost over the 2005 to 2025 time horizon. Cumulatively, as much as 3.9 billion barrels of oil and 45 Tcf of natural gas would not be produced by 2025.

Under the Higher Impact scenario, over the 2005 to 2010 time period this could result in:

- $2.0 billion (discounted) per year increase in the nation's expenditures for oil imports ($2.4 billion undiscounted).
- $180 million per year less in royalties collected by the federal government ($210 million undiscounted).
- $465 million per year less paid to private landowners in oil and gas royalties ($545 million undiscounted).
- $225 million per year in lost tax revenues accruing to state government from severance taxes alone ($265 million undiscounted).

Over this time period, natural gas consumers would pay from $1.1 to $6.5 billion (discounted) more for natural gas per year, on average, over the 2005 to 2010 time horizon ($1.3 to $7.9 billion undiscounted) higher due to higher natural gas prices

Over the entire 2005 to 2025 time period for which the analysis was performed, the following impacts would result:

- $2.6 billion (discounted) per year increase in the nation's expenditures for oil imports ($4.7 billion undiscounted).
- $260 million per year less in royalties collected by the federal government ($470 million undiscounted).
- $670 million per year less paid to private landowners in oil and gas royalties ($1.2 billion undiscounted).
- $325 million per year in lost tax revenues accruing to state government from severance taxes alone ($590 million undiscounted).

Moreover, the proposed requirements under the Higher Impact scenario could result in natural gas consumers paying from $2.9 to $17.8 billion more (discounted) for natural gas per year, on average, by 2025 due to higher natural gas prices ($5.7 to $35 billion undiscounted).

Again, it is worth noting that the impacts estimated for this Higher Impact scenario should not be considered to be those associated with a "worst case" scenario, as discussed in the following section.

CAVEATS

Nature of Assumptions

Substantial uncertainty is associated with many of the assumptions used in this analysis. Moreover, since EPA has yet to publish any proposed requirements specifically for the oil and gas sector, certain assumptions about compliance requirements may turn out to be different than what EPA proposes, or what is currently required under the CGP. For the most part, the characterization of new compliance requirements in this analysis is based on current requirements in the CGP.

Some of the more important, though uncertain, assumptions are described below.

Length of Project Delays. The major uncertainties characterizing the range of potential economic impacts on the oil and gas industry presented in this assessment primarily relate to the permitting delays that could take place as a result of implementation of the Phase II requirements. These pertain to the anticipated processes required for endangered species and historical/archeological reviews, and the time it might take to process permit applications, make determinations, and grant approvals. If these processes proceed efficiently and according to schedule, anticipated economic impacts (although still considerable) can be minimized. If these processes are cumbersome, contentious, and prone to delays, the economic impacts can be quite large, with substantial impacts on domestic energy supplies, our nation's balance of trade and dependence on foreign energy supplies, and the price Americans pay for the energy they consume.

Definition of Construction. The assessment only considered activities associated with new "construction" projects, i.e., one-time activities at the initiation of operations. Maintenance or repair projects associated with drilling and production operations (such as well workovers and other well services), are not considered "construction" projects in this assessment. In the area of gas and liquids transportation, EPA has redefined maintenance to exclude repairs and replacement; as such, these activities are subject to permitting requirements. While it can be argued that pipeline integrity management activities are an intrinsic component of pipeline operations and are therefore industrial activities not subject to storm water permitting, EPA's narrowing of the maintenance definition requires that such activities be included in estimating potential impacts of the proposed Phase II requirements. In this analysis, the pipeline activities included installation of small segments of new pipelines, surface facility additions or expansions, and repair/replacement activities in which the original intent was to repair or replace a segment of pipeline. However, it did not include situations where the original intent complied with EPA's definition of maintenance, and at some point in the work it was identified that it was necessary to repair or replace a segment of pipeline. If such activities must comply with the Phase II requirements, the economic impacts presented here are grossly understated.

Delays Associated with Permit Reviews. In this assessment, it was assumed that NRDC does not prevail in its argument requiring EPA to individually review the NOIs and SWPPPs prepared under the general permit process, and to require a process for public notice, comment, and opportunity for public for every NOI and SWPPP submitted. Similarly, it was assumed that NRDC does not prevail in its argument that EPA should be required to review each operator's permit application and, in consultation with the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), determine the extent to which adverse effects may occur to endangered species in the project area. However, if NRDC were to prevail, the case-by-case review and public participation requirements they seek to impose would increase still further the already very significant potential of the CGP requirements to delay oil and gas drilling, increasing the potential for lease forfeiture and lost reserves.

Learning Curve Efficiencies. Like most economic impact assessments of this type, no consideration was given to the fact that over time, processes for compliance, performed by both operators and by regulatory agencies, would improve, and become more efficient and subsequently less costly and/or with less delay. Recognizing this, the presentation of results focused on the annualized impacts over the first five years after promulgation – the period of time where the impacts of such efficiency gains would be least likely to be realized.

Impacts not Considered

It is also important to note that these impacts represent only some of the costs associated with increased compliance costs and potential project delays. Other possible impacts that were not considered in this impact assessment include:

- *Any incremental costs that may be incurred to ensure compliance* (such as installing erosion control systems) or to mitigate possible impacts to endangered species or historic sites. The only costs considered are only those associated with filing NOIs, ensuring that a SWPPP has been completed, demonstrating that BMPs are installed according to SWPPP, completing periodic inspections, and demonstrating that the site has been stabilized prior to filing a NOT.
- *Other delay costs other that rig costs*. These would include increased fees associated with delaying work by well service contractors, stimulation contractors, and other service companies that could not perform their services on schedule because of project delays.
- *Increased costs of project financing*, as a result of greater project uncertainty that could impact the ability of potential operators to secure financing and/or joint venture partners for specific projects. Some believe that the new requirements will substantially increase the risks associated with drilling prospects, impacting the risk/reward profile of prospective lenders and investors.

- *Decreased value of oil and gas company stocks*. Some believe that these Phase II requirements may impact the SEC reserve calculations for public companies, which may have to write down their reserve base, resulting in a loss of investor confidence and lower stock price valuations.

Finally, no estimate was developed for the potentially significant economic impacts to industry and to communities resulting from Phase II permitting delays in performing pipeline maintenance and repair work, primarily because the impacts are so significant that it is highly unlikely that society would permit this to occur. Under the integrity management program of the Department of Transportation (DOT), pipelines with certain anomalies are required to be repaired within a given time frame or to reduce or shut down throughput. In many instances, this can mean shutting down or reducing service to an entire community until the anomaly can be repaired or replaced.

Under the current CGP, EPA redefined such maintenance to exclude repairs and replacement, with these activities subject to the Phase II permitting requirements. The delays associated with permitting may be as short as 7 days, but have traditionally often been much longer. In one state, permit processing by the agency can, by regulation, take up to 90 days; several other states have adopted agency review periods of 30-60 days. Under the current EPA interpretation of such maintenance activities, the potential cost per day of eliminating gas service to an entire community to await permit approval for pipeline repairs could be economically catastrophic for that community.

Moreover, in all aspects of the oil and gas industry, there are potential situations when actions which must be taken immediately to protect employees, the public, and the environment, and/or to comply with other regulations. The most obvious of these are spill response activities or the repair of a pipeline failure. The current Phase II requirements provide no mechanism for emergency responses to protect human health and safety and the environment. This could apply to both emergencies (e.g., containment of the spill may be an emergency response) and non-emergency actions (e.g., the cleanup may not be an emergency but requires timely and prudent non-emergency action). Under the current Phase II process, a company must either respond quickly, and thus not comply with the requirements, or wait for the permitting process to proceed, and thus delay responding expeditiously to the emergency.

Because it is likely that the public will find this situation unacceptable, the estimated economic impacts associated with this type of circumstance was not estimated in this assessment. However, it further demonstrates how the Phase II requirements, as currently set forth in the CGP, have severe limitations if applied to oil and gas industry operations.

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